DAYMARK ENERGY ADVISORS

To: RHODE ISLAND PUBLIC UTILITIES COMMISSION

From: Matthew Loiacono, and Aliea Afnan, DAYMARK ENERGY ADVISORS

Date: March 12, 2019

Subject: 2019 Retail Rates Filing – Docket No. 4930

INTRODUCTION

On February 15, 2019, National Grid (NGrid or the Company) filed its 2019 Retail Rate Filing. This filing consists of rate adjustments arising out of the reconciliation of the Company's Standard Offer Service (SOS), SOS administrative costs, the non-bypassable transition charge, transmission service charge, the transmission-related uncollectible expense charge, the Net Metering Charge, and the Long-Term Contracting for Renewable Energy Recovery Factor (LTC Recovery Factor). The reconciliation period for the various costs in this filing is January 2018 through December 2018. The proposed rate adjustments are effective for usage on and after April 1, 2019. The net effect of all proposed rate changes for a typical residential SOS customer is a 2.6% decrease. Based on the Public Utility Commission's (PUC's) Orders in Dockets 4599 and 4691, the Company has provided Excel files of its workpapers supporting the 2019 Annual Retail Rates Filing. This filing was designated as Docket No. 4930.

The Rhode Island Division of Public Utilities and Carriers (the "Division") has retained Daymark Energy Advisors to assist in its review of this filing to ensure the various reconciliations are accurately calculated and are in accordance with the relevant tariffs. In summary, we find that NGrid calculated all the charges appropriately based on the underlying data the Company presented and the Company's tariff. However, we make the following recommendation:

- Regarding the Transmission Service Reconciliation, the Company should use actual December 2018 expenses in place of the estimated expenses, if they are available, before adjusting rates April 1, 2019.

This memorandum presents the full results of our review.

STANDARD OFFER SERVICE ADJUSTMENT FACTORS

The Company is proposing to adjust two Standard Offer Service (SOS)-related rate charges: (1) an adjustment factor to collect (or refund) net under (or over) recovery of SOS expense and (2) the standard offer service administrative cost adjustment factor, which is the sum of an administrative cost factor designed to collect various projected administrative expenses related to the provision of SOS and an SOS administrative cost reconciliation adjustment factor, which accounts for any under- or over-recovery of prior period SOS administrative costs.

For the first charge, the SOS reconciliation adjustment, the filing at Schedule REP-2, p. 1, shows a net over-recovery (with interest) of approximately $3.7 million in calendar year (CY) 2018, compared to the over-recovery (with interest) of approximately $2.2 million in CY 2017. This CY 2018 total is a sum of the separately-calculated totals for each of the three SOS customer groups: Residential, Commercial, and Industrial. These totals are then adjusted for additional interest during the recovery period and divided by forecasted customer group SOS kWh sales for April 2019 through March 2020 to calculate three different adjustment factors, one for each procurement group. The Residential group had an over-recovery (with interest) of approximately $5.6 million. The Commercial and Industrial groups had under-recoveries (with interest) of $1.5 million and $378,383, respectively. These SOS ending balances were the result of revisions made to the calculation of a part of the January 2019 revenue tied to kWh deliveries made in December 2018 and billed in January 2019. The Company chose to make these revisions now to better align revenue related to this reconciliation period.

Additionally, as a result of Docket 4692 and Docket 4809, the Company is proposing normalizing adjustments to the Residential and Commercial SOS reconciliations, which will reduce the amount recovered through the proposed SOS adjustment factors, to reflect additional revenue as if the Company had billed the SOS rates. NGrid explained that the PUC directed the Company to reduce SOS rates for the Residential and Small Commercial and Industrial C-06 fixed rate classes to a lower value for the October 2018 through March 2019 period and further directed the Company in Docket 4809 to increase SOS rates for April 2019 through September 2019 to recover the deferred revenue.[1] The normalizing adjustments are meant to accomplish the following:[2]

1. Remove unintended consequences from reducing the Small Commercial and Industrial C-06 fixed rate on other Commercial customers; and

[1] Testimony of Robin E. Pieri, p. 8, lines 1-6.

[2] Testimony of Robin E. Pieri, pp. 8-9, lines 15-21 and 1-12.

2. Address the timing difference between the recovery of deferred revenue (October 2018 through March 2019) and directive to recoup the revenue from the following six-month pricing period (April 2019 through September 2019). This leads to the Company recouping the loss in revenue to be better aligned with the impact of the lower SOS rates.

The normalizing adjustments were calculated by taking the difference between the actual billed revenue for the October through December 2018 period, inclusive of revenue billed in January for December kWh deliveries, and the estimated revenue that would have been billed had the proposed SOS rates been implemented. This resulted in additional revenue to Residential and Commercial SOS reconciliations of approximately $7.2 million and $1 million, respectively, that started 2019 as under-recovered amounts reflecting the deferred revenue for October 2018 through December 2018.[3] Without the $8.2 million revenue adjustment, all three classes would have been under-recovered (Residential class at $1.6 million, Commercial class at $2.5 million, and the Industrial class at $0.3 million). NGrid explained that the under-recovery for the Residential and Commercial classes was due to higher than forecasted kWh during months where costs for SOS were higher than the rate billed. Under-recovery for the Industrial class was due to timing differences.[4]

The SOS reconciliation adjustment for CY 2018 included the additional following adjustments: $16,265 reflecting the remaining balance of CY 2016 net under-recovery SOS expenses; and increased the SOS reconciliation by $7,234 for unbilled SOS Billing Adjustments for CY 2018. The net unbilled billing adjustment revenue for CY 2018 is the combination of a positive $19,954 for Residential and a negative $12,721 for Commercial SOS customers. These amounts equate to a debit or revenue shortfall of $7,234, which means the Company paid more for the SOS supply of customers than it billed to the customers that left SOS and took electric supply from a third party.[5] NGrid is proposing this amount as an adjustment to the Revenue Decoupling Mechanism (RDM)[6] reconciliation, which will be filed by May 15, 2019.[7] Through the RDM Adjustment Factor, all customers will be assessed a portion of the net SOS Billing Adjustment debit.

On a per kWh basis, the charge with the largest magnitude SOS adjustment is a 0.223 cents/kWh credit for the Residential class. The SOS adjustment for the Industrial class a charge of 0.138 cents/kWh, while the Commercial class will be charged 0.154 cents/kWh. Regarding the Industrial class, this charge represents a shift from the previous several years of large credits the class had been receiving. The high

[3] Testimony of Robin E. Pieri, pp. 9-10, lines 14-20 and 1-5.

[4] Company response to Division 1-1(a), p. 2, in Docket No. 4930.

[5] Testimony of Robin E. Pieri, p. 18, lines 8-17.

[6] The RDM Adjustment Factor is a uniform per kWh factor applicable to all retail delivery service customers.

[7] Testimony of Robin E. Pieri, p. 19, lines 1-3.

refund rate the Industrial class experienced in 2015 (1.014 cents/kWh) was previously explained by NGrid as a combination of customer migration to alternative suppliers due to the winter of 2014-2015, invoicing errors, and a decrease in forecasted deliveries based on the prior year's customer migration. Further, although the Company had experienced lost kWh sales over the last couple of years, it provided an Industrial SOS kWh forecast for April 2018 - March 2019 that was 7% higher than the forecast for April 2017 through March 2018, as shown in the figure below. In discovery, the Company explained that the increase in the forecast was due to the present proportion of kWh deliveries to Industrial SOS customers increasing from 9.53% to 10.39%, which offset the decrease in the total Industrial kWh forecast.[8] This trend has continued in the Industrial SOS kWh forecast for April 2019 through March 2020, as the Company shows in Schedule REP-3, page 2, that the proportion of kWh deliveries to Industrial SOS customers increased from 10.39 % to 11.99%, which offsets the decrease in the total Industrial kWh forecast.

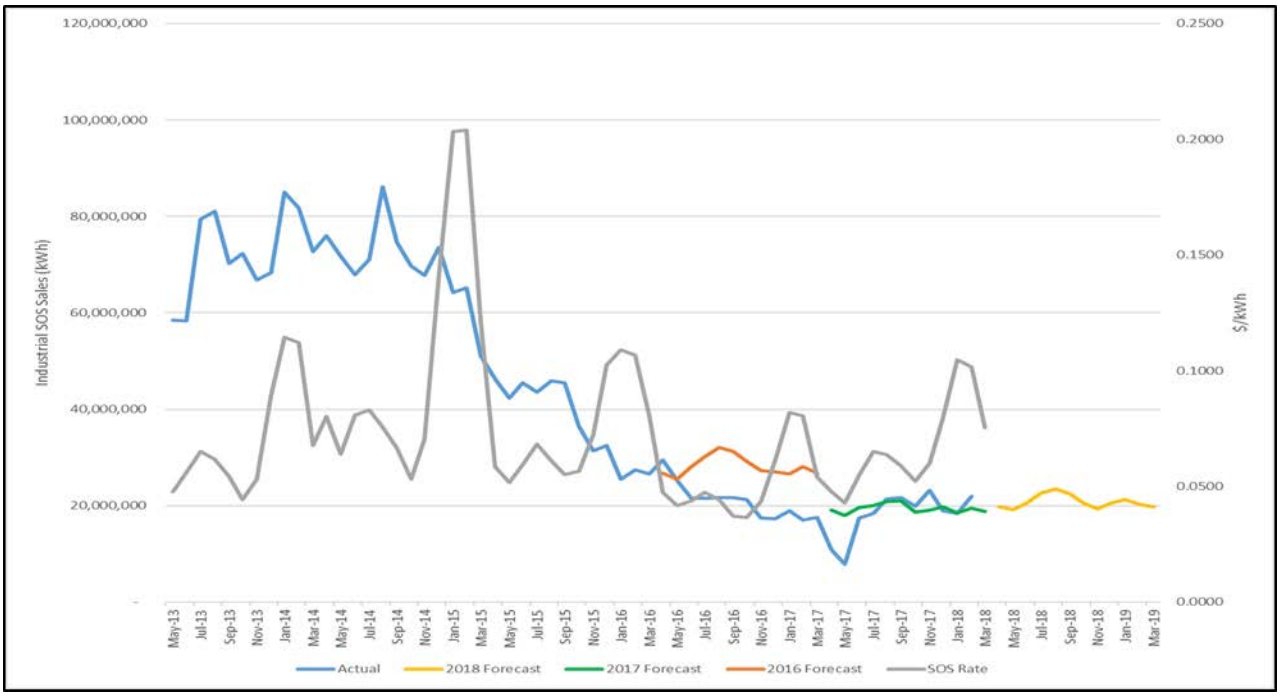

Figure 1. Actual and project SOS sales for the industrial class compared to industrial SOS rates.

Additionally, we note that the Company is proposing to credit the Residential class 0.223 cents/kWh compared to the current charge of 0.007 cents/kWh and charge the Commercial class 0.154 cents/kWh compared to the current credit of 0.041 cents/kWh. When asked in Docket 4805 about the swings in net

[8] Company response to Division 1-1(c) in Docket No. 4805.

over- and under-recovery to the different SOS groups, the Company provided four factors that can contribute to these swings: (1) Fixed prices for the Residential and Commercial classes are developed using monthly kWh estimates that may differ from the actual monthly distribution across the rate period; (2) line losses used to develop SOS retail rates are estimated and may vary from actual line losses; (3) estimated spot market prices are used to develop the retail SOS rates and actual spot market prices may differ; and (4) customers are billed on a billing cycle basis while the Company is billed for SOS expenses on a calendar month basis.[9] Additionally, NGrid explained that changes in the Residential and Commercial classes' SOS adjustment factors in last year's filing, Docket 4805, were due to a transition period of the Company switching from pricing periods of January to June and July to December (2015) to periods from January to September and October to March (2016-2017). During the transition period, the first three months are expected to have an over-recovery due to variable rates being lower than the per kWh charge. The second three months of the transition period were expected to have higher variable rates, leading to an under-recovery. NGrid expected these to balance out during the transition period and not continue after. Our review indicates the SOS reconciliation adjustment factors are consistent with the underlying data and tariff R.I.P.U.C. No. 2113 and are reasonable.

The administrative cost factor includes an allowance for SOS uncollectible expense and several administrative cost elements (chief of which is cash working capital). The 2019 filing shows total administrative expense of approximately $7.5 million[10] compared to approximately $6.2 million in the 2018 filing. Uncollectible expense is higher than last year due to higher projected SOS rates for all three classes.[11] The cash working capital requirement is $32.9 million[12], compared to $23.4 million in the 2018 filing.[13] This increase was mostly due to a combination of higher Purchased Power Invoices (about $11.6 million higher than 2017) and Spot Market Purchase Invoices (about $75.4 million[14] higher than 2017).[15] NGrid noted that about $2.2 million was removed from the 2017 reconciliation and added to a January 2018 Spot Market Purchase Invoice.[16]

[9] Company response to Division 1-1(a) in Docket No. 4805.

[10] Schedule REP-4, p. 1.

[11] Schedule REP-4, p.2.

[12] Schedule REP-6, p. 1.

[13] Still substantially high because of an $80.7 million adjustment to the Customer Accounts Receivable balance in December 2014 labeled in NGrid's workpapers from Docket No. 4559 as due to reclassifying gas to electric.

[14] Schedule REP-6, p. 2 shows that a $150,859 credit was applied to an August 2018 Purchased Power Invoice for a Calpine resettlement.

[15] Schedule REP-6, pp. 2-5 and Schedule ASC-6, pp. 3-6 (Docket 4805).

[16] Schedule REP-6, p. 4.

As with the SOS adjustment factor, separate cost factors are calculated for the three customer groups. Reconciliation of these costs is added to these totals for each customer group. For the 2019 filing, the Company reports a net under-collection of 2018 administrative costs of approximately $1.4 million (with interest).[17] The Residential, Commercial, and Industrial customer groups showed under-collections of $885,716, $386,791, and $98,125 respectively.[18] This net under-collection is largely due to a combination of higher expenses than revenues for all three customer groups.[19]

Both the estimated administrative costs and over-collection of 2019 administrative costs are divided by the forecast SOS kWh sales by customer group to arrive at three different factors. We find NGrid's calculation of these charges appears to be supported by the data and should be approved.

TRANSITION CHARGE

NGrid is requesting changes to both the transition charge and transition adjustment charge, which is used to account for prior under- or over-collection of these costs. For 2019, the adjustment charge is due to an over-collection of charges in CY 2018. The transition adjustment charge is calculated by dividing the over-recovery balance from 2018 by the forecasted kWh deliveries during the recovery period, April 2019 through March 2020. This adjustment incorporates the final balance of over-recovery incurred in CY 2016.

The transition charge itself is a function of the contract termination charges (CTC) billed to NGrid by New England Power Company (NEP) and Montaup. The CTC charge is calculated by aggregating the individual CTC charges and dividing them by the total GWh deliveries, resulting in a weighted average base Transition Charge. The previous transition charge was a credit primarily because NEP and Montaup received net credits for actual nuclear decommissioning and other post shut-down costs, which were estimated to be zero starting in 2011. Connecticut Yankee, Maine Yankee, and Yankee Atomic filed suit against the Department of Energy (DOE) for the its failure to remove the Yankees' respective spent nuclear fuel stores as required by law. So far, money has been awarded in three Phases, covering different time periods.[20] NEP and Montaup received proceeds for Phase I and Phase II of the litigation that were credited to customers between 2013 and 2015. No proceeds were returned by NEP and Montaup from October 1, 2015 through September 30, 2016.

[17] Schedule REP-5, p. 1.

[18] Schedule REP-5, pp. 2-4.

[19] Additionally, the net over-collection is still partially impacted by the December 2014 adjustment to the cash working capital requirement.

[20] In May 2017, Phase IV of the litigation was filed by the Yankees to cover 2013-2016.

According to the 2017 CTC Reconciliation Reports[21] filed by NGrid, in December of 2016 NEP received $5.9 million in proceeds and Montaup received $1.7 million in proceeds for Phase III litigation, which they planned to return to customers in the following year's CTC reconciliation. In the 2018 CTC Reconciliation Reports[22] filed by NGrid, Phase III litigation proceeds were received in December of 2016 by Montaup and NEP in the amounts of $3.2 million and $14.8 million, respectively, and were credited to customers through the 2017 CTC reconciliation filed in January 2018.[23] NGrid did not receive excess proceeds from NEP[24] or Montaup[25] to return to customers from October 1, 2017 through September 30, 2018, but is returning $6.3 million for October through December 2018 for NEP and about $3.3 million in December 2018 for Montaup.[26,27] In discovery, NGrid explained that the Phase III litigation proceeds described in the 2018 CTC Reconciliation Reports replaced the amounts originally provided in the 2017 CTC Reconciliation Reports.[28] The discrepancy between the 2017 and 2018 Phase III litigation proceeds for Montaup and NEP was due to changes in how Connecticut Yankee and Maine Yankee handled the proceeds. Connecticut Yankee received $32.6 million of litigation proceeds instead of $34.6 million and the company only returned $18.4 million to wholesale customers instead of the entire amount, as originally intended. The Company deposited $0.6 million of proceeds in its irrevocable external trust to fund Post Retirement Benefits Other Than Pension (PBOP), used $0.4 million of proceeds to pay the associated taxes, and deposited the remaining proceeds into the Decommissioning Trust Fund to fund long-term Independent Spent Fuel Storage Installation (ISFSI) operations and decommissioning costs.[29] Maine Yankee was awarded $24.6 million in damages, of which $3.6 million were returned to the Company's wholesale customers in December 2016, and remaining proceeds were deposited into the Decommissioning Trust Fund.[30] Yankee Atomic was awarded $19.6 million, all of which was deposited in the Decommissioning Trust Fund.[31]

[21] Reconciliation of Contract Termination Charge to the Narragansett Electric Company and Reconciliation of Contract Termination Charge to Blackstone Valley Electric Company and Newport Electric Corporation, each submitted in January 2017.

[22] Reconciliation of Contract Termination Charge to the Narragansett Electric Company and Reconciliation of Contract Termination Charge to Blackstone Valley Electric Company and Newport Electric Corporation, each submitted in January 2018.

[23] Company response to Division 1-6(b), p. 3, in Docket 4930.

[24] Narragansett has a 22.4% share of the NEP proceeds.

[25] Blackstone and Newport have shares of 29.13% and 11.85%, respectively.

[26] Company response to Division 1-6(b), Attachment DIV 1-6-1, pp. 10 and 14, in Docket 4930.

[27] Company response to Division 1-6(b), Attachment DIV 1-6-2, pp. 7, 10, and 11, in Docket 4930.

[28] Company response to Division 1-4 in Docket 4805.

[29] Company response to Division 1-6(b), p. 2, in Docket 4930.

[30] Company response to Division 1-6(b), p. 2, in Docket 4930.

[31] Company response to Division 1-6(b), p. 2, in Docket 4930.

Phase IV proceeds have been initially awarded in the amounts of $40.7 million to Connecticut Yankee, $28.1 million to Yankee Atomic, and $34.4 million to Maine Yankee. The federal government has until April 22, 2019 to appeal the decision, otherwise the proceeds will be returned to customers.[32]

Based on the credits to customers from the Phase III litigation proceeds, the base transition charge credit factor for the upcoming year is 0.093 cents/kWh. When combined with the transition charge adjustment factor credit of 0.021 cents/kWh, the proposed total transition charge credit factor is 0.114 cents/kWh.[33] The change in the transition charge compared to last year's filing is primarily due to the changes in credits being returned to customers during CY 2018.

Overall, we find the base transition charge credit to be consistent with the NEP charges reported in the NEP and Montaup CTC Reconciliation Reports. We also find that the adjustment factor charge credit to be consistent with the underlying data presented and the Company's tariff. We recommend that both charge credits be approved.

TRANSMISSION SERVICE CHARGE

The Company has estimated its 2019 costs for transmission service to be $197.8 million, as described by the testimony of Tiffany M. Forsyth. Table 1 below provides a summary of this estimate and compares it to previous estimates used to establish transmission service charges in the two previous years. The forecasted transmission costs from 2017 to 2018 decreased by $4.6 million (2%), while the 2019 projected value decreases the transmission costs by $10.3 million (5%) relative to the 2018 transmission costs.

[32] Company response to Division 1-6(b), p. 3, in Docket 4930.

[33] Testimony of Robin E. Pieri, p. 20.

NARRAGANSET ELECTRIC COMPANY

SUMMARY OF TRANSMISSION COSTS

Ln #	Item		Feb-17	Feb-18	Incr/(Decr)	Feb-19	Incr/(Decr)	% Change
	NEP Local Charges							
1	Non-PTF Demand Charges		$ 31,259,601	$ 32,871,310	$ 1,611,709	$ 25,946,640	$ (6,924,670)	-27%
2	Other NEP Charges		$ 496,093	$ 273,453	$ (222,640)	$ 360,615	$ 87,162	24%
3	BITS Surcharge		$ 32,680,356	$ 21,925,423	$ (10,754,933)	$ 20,272,480	$ (1,652,943)	-8%
4		*Subtotal*	$ 64,436,050	$ 55,070,186	$ (9,365,864)	$ 46,579,735	$ (8,490,451)	-18%
	ISO-NE Regional Charges							
5	PTF Demand Charge		$ 140,564,339	$ 145,847,743	$ 5,283,404	$ 144,304,593	$ (1,543,150)	-1%
6	Scheduling & Dispatch		$ 2,308,148	$ 2,225,931	$ (82,217)	$ 1,971,263	$ (254,668)	-13%
7	Black Start		$ 969,522	$ 776,594	$ (192,928)	$ 877,984	$ 101,390	12%
8	Reactive Power		$ 1,371,053	$ 1,249,058	$ (121,995)	$ 1,296,001	$ 46,943	4%
9		*Subtotal*	$ 145,213,062	$ 150,099,326	$ 4,886,264	$ 148,449,841	$ (1,649,485)	-1%
	ISO-NE Administrative Charges							
10	Schedule 1 - Scheduling & Dispatch		$ 2,778,212	$ 2,625,632	$ (152,580)	$ 2,461,473	$ (164,159)	-7%
11	Schedule 3 - Reliability Admin. Service		$ 190,145	$ 192,185	$ 2,040	$ 201,233	$ 9,048	4%
12	Schedule 5 - NESCOE		$ 104,564	$ 95,784	$ (8,780)	$ 105,915	$ 10,131	10%
13		*Subtotal*	$ 3,072,921	$ 2,913,601	$ (159,320)	$ 2,768,621	$ (144,980)	-5%
14		**Total**	**$ 212,722,033**	**$ 208,083,113**	**$ (4,638,920)**	**$ 197,798,197**	**$ (10,284,916)**	**-5%**

Table 1. Summary of 2017-2019 Transmission Costs

Table 2 below provides a recapitulation of the proposed decrease by major cost drivers. Of the approximate $10.3 million decrease, a decrease of about $8.5 million in the forecasted NEP local charges is the primary cost driver in conjunction with a decrease of about $1.8 million in the ISO-NE Regional and Administrative Charges.

RECAP OF DIFFERENCES

Item		Incr/(Decr)
PTF Demand Charge	$	(1,543,150)
Non-PTF Demand Charges	$	(6,924,670)
Other NEP Charges	$	87,162
BITS Surcharge	$	(1,652,943)
ISO Charges	$	(251,315)
Subtotal	$	(10,284,916)
Resettlement Charges	$	-
Refund Charges	$	-
Subtotal	$	-
Total	**$**	**(10,284,916)**

Table 2. Reasons for the 2019 Decrease in Transmission Costs

NGrid explained that the decrease in the forecasted ISO-NE Regional Charges is primarily driven by an expected decrease in Pool Transmission Facility (PTF) Demand Charges due to the lower forecasted Regional Network Service (RNS) rate for 2019 when compared to 2018.[34] The RNS rate of $117.17 kW-yr (June 1, 2019 through May 31, 2020) is comprised of the total RNS rate through May 31, 2019 ($110.43/kW-yr) plus the additional estimated ISO RNS rate ($6.74/kW-yr).[35] In Docket 4805, the RNS rate was $119.55/kW-yr for June 1, 2018 through May 31, 2019 where the total RNS rate through May 31, 2018 was $111.96/kW-yr and the additional estimated ISO RNS rate was $7.59/kW-yr.[36] The Company developed its projection of PTF costs from a presentation by the Pool Transmission Owners Administrative Committee (PTO AC) Rates Working Group's presentation to the New England Power Pool (NEPOOL) Reliability Committee/Transmission Committee at the summer meeting on August 7-8, 2018. We have reviewed this presentation and find it to be a reasonable source for a 2019 rate for RNS.

The estimate of Non-PTF costs incorporates NGrid's estimates of Non-PTF plant additions.[37] These costs are estimated on a project-by-project basis. The Company provided the project-by-project costs by

[34] Testimony of Tiffany M. Forsyth, p. 20.

[35] Schedule TMF-3, p. 1.

[36] Docket 4805, Schedule PVD-3, p. 1

[37] Company provided a list of these additions to the Division through its response to Division 1-2 in Docket No. 4805.

state.[38] The Non-PTF projects in 2019 for Massachusetts ($42.7 million), Rhode Island ($40.3 million), New Hampshire ($2.1 million), and Vermont (0.1 million) total $85.2 million.[39] We have reviewed these estimates and find them to be reasonable. The increase in Non-PTF Demand charges is due to a lower estimated revenue requirement.

As shown in the tables above, the BITS Surcharge is another NEP charge to NGrid, put into effect on November 1, 2016. This surcharge was approved by the FERC, under Schedule-21 of the ISO/RTO Tariff, to recover the Company's share of the costs for the Block Island Cable and associated facilities linked with the Town of New Shoreham Project. This project is a public policy undertaking that allows for the construction of a small-scale offshore wind demonstration project off the coast of Block Island. Annual costs of these facilities will be recovered through a reconciling rate adjustment from NGrid's customers and/or from the Block Island Power Company (BIPCo). The BITS Surcharge allocation to NGrid is calculated by multiplying the integrated facilities credit received by the Company through NEP's FERC Electric Tariff No. 1 (IFA Facilities Credit), updated around June each year, by NGrid's Load Share Percentage (one (1) less BIPCo's Load Share Percentage based on the prior year's load data). Costs are then passed through to retail customers under the Transmission Service Cost Adjustment. In this forecast, the estimated BITS Surcharge to Narragansett for the April 2019 through March 2020, which is about $1.7 million lower than last year's filing, is based on the expected monthly gross plant investment balances times the current carrying charge times the allocation to Narragansett.

Schedule TMF-7 provides the estimated annual surcharge calculation, which is passed through to customers under the Transmission Service Cost Adjustment. The annual surcharge is subject to change based on the carrying charge, currently 17.86%, which is updated each year and was calculated using NGrid's CY 2017 FERC Form 1 data per the provisions of NEP's Electric Tariff No.1 (Line 14 note in Schedule TMF-7).

The Company proposes to recover the estimated 2019 costs via demand and energy charges, as appropriate for each rate class. Schedule REP-11 provides the details of this allocation. The allocators used to assign estimated transmission costs to each rate class are a weighted average of energy use for 12 months ending 12/31/2008, 12 months ending 12/31/2011 and 12 months ending 6/30/2017 (Test Year used in the Company's recent rate case – Docket 4770), as these are years with relatively normal weather. The use of more recent years to develop the allocators was ordered by the PUC in Docket 4805 based on our recommendation.

[38] Company response to Division 1-5(b), Attachment DIV 1-5_B.

[39] The $85.2 million corresponds to Schedule TMF-6, p. 1, line 4.

Based upon the above discussion, we find the Company's forecast of 2019 transmission cost and the rates designed to recover that amount to be reasonable. We recommend that the Commission approve the charge.

TRANSMISSION SERVICE RECONCILIATION

The previous year's forecast of transmission service charges is reconciled against 2018 actual transmission service revenues and expenses. Schedules REP-12 and REP-13 provide the basis for this reconciliation. As of the beginning of 2018, the cumulative variance between revenues and expenses, not including interest, is an over-collection of $20,609,471, as calculated in REP-12. The Company will refund this over-collection over the period of April 1, 2019 through March 31, 2020. Additional interest during this period is estimated by the Company to be $212,039, which brings the total to be refunded to $20,821,511. The beginning balance for January 2018 was a negative $1,747,573, which was a "true-up" of the estimated December 2017 transmission expenses from Docket 4805 with the actual December 2017 expenses.[40] In discovery, the Company explained that November and December expenses in 2018 equaled $191.8 million, which was $16 million lower than forecasted, due to the Company only including the partial impact of the lower federal tax reform.[41] Like in the previous filing, NGrid estimated December 2018 expenses based on December 2017 actuals.[42] This year the Schedule REP-13 determines the cents/kWh rate for each customer class that will be refunded to each class' share of the over-collection. Using a representative sample analysis, we find the calculations in Schedule REP-13 to be accurate.

We find the Company's 2019 transmission reconciliation over-recovery and the rates designed to refund that amount to be reasonable and recommend that they be approved. However, we recommend that before adjusting rates April 1, 2019, the Company use actual December 2018 expenses in place of the estimated expenses, if they are available.

TRANSMISSION-RELATED UNCOLLECTIBLE EXPENSE

The Company's Transmission Service Cost Adjustment Provision (TSCAP) allows it to collect from customers an estimate of transmission-related uncollectible accounts receivable, currently equal to 1.30% (changed from 1.25% in Docket 4770 Settlement Agreement) of the estimated amount of transmission costs to be incurred during 2019. Schedule REP-14 provides the calculation of this amount. The TSCAP also requires the Company to reconcile its forecast of the transmission-related uncollectible

[40] Testimony of Robin E. Pieri, pp. 26-27.

[41] Company response to Division 1-4(a) in Docket 4930.

[42] Company response to Division 1-4(b) in Docket 4930.

accounts receivable for 2018. This reconciliation occurs only for actual 2018 revenue. Schedule REP-15 provides these reconciliation calculations. We note that the reconciliation calculations in Schedule REP-15 for 2018 used a weighted uncollectible factor of 1.27% (8 months of 2018 at 1.25% and 4 months at 1.30%). Using a representative sample analysis, we find the calculations in Schedule REP-14 and REP-15 to be accurate and recommend that the rates contained therein be approved.

NET METERING CHARGE

The net metering charge recovers the costs of renewable net metering credits and payments to qualifying facilities in excess of payments the Company receives from ISO-NE for the sale of this energy in the market. The Company is proposing a Net Metering charge change to 0.068 cents/kWh[43] from 0.043 cents/kWh. In calculating the Net Metering reconciliation, the Company included an adjustment in January 2018 of $27,310, which represents an adjustment to a Net Metering Facility payment that had not been reflected in the Company's annual retail rate filings. NGrid explained that it had reflected these energy sales as either energy sales for Long Term Contract facilities or as offsetting credits to SOS Spot Market energy purchases. As a result, reconciliations in prior years had understated Qualifying Facilities Power Purchase Recoverable Costs. Now all customers billed the net metering charge have all costs and proceeds correctly reflected. Additionally, NGrid made an adjustment of $20,939 in April 2018 for the remaining unrecovered balance of the costs incurred during 2016 and recovered from customers during the period that ended March 31, 2018.[44] NGrid's calculation of this charge appears to be supported by the data and should be approved.

LONG-TERM CONTRACTING FOR RENEWABLE ENERGY RECOVERY RECONCILIATION FACTOR

The current base LTC Recovery Factor is a 0.616 cent/kWh charge. NGrid proposes to add to this an LTC Recovery Reconciliation Factor of 0.062 cent/kWh[45], in accordance with tariff R.I.P.U.C. No. 4673.[46] The LTC Recovery Reconciliation Factor is used to collect (or refund) any under- (or over-) recovery of LTC expenses. For 2018, NGrid reports an under-recovery of approximately $4.42 million (with interest)

[43] Schedule REP-16, p. 1.

[44] Testimony of Robin E. Pieri, pp. 36-37.

[45] Schedule REP-18, p. 1.

[46] In response to Division 1-7(c), p. 2, the Company explained that a July 2018 expense of $37,102.50 was removed from the reconciliation, causing no change in the factor, because it was related to a consultant, and some employee labor cost, from bidding the capacity of the Renewable Growth Program's distributed generation units into the Forward Capacity Market during 2018, not related to bidding capacity of Long Term Contracting renewable energy resources. This expense will be included in the cost of the RE Growth Program's reconciliation in January 2019.

compared to $4.96 million (with interest) in 2017. The under-recovery amount is net of REC proceeds from RECs purchased through long-term contracts for renewable energy. To estimate the REC proceeds, NGrid must calculate a transfer price. NGrid provided the transfer price in its workpapers, and it appears to be reasonable. The under-recovery balance reflects an adjustment of $161,049 shown in April 2018.[47] This adjustment represents the remaining unrecovered balance of the under-recovery incurred during 2016 and recovered from customers during the period ending March 31, 2018. NGrid's calculation of the LTCRER reconciliation factor appears to be supported by the data provided and is in accordance with R.I.P.U.C. No. 4673. The proposed rate should be approved.

[47] Testimony of Robin E. Pieri, p. 40.

Matthew C. Loiacono

Consultant

Matt provides clients economic and policy analysis on matters including rates, grid modernization, capital expenditures, and net energy metering. He has analyzed approaches to renewable resource integration and the benefit-cost of various modes of participation on wholesale energy market performance. He advises clients on energy procurement strategy and administers procurement auctions on their behalf.

INDUSTRY EXPERIENCE

Daymark Energy Advisors | www.daymarkea.com | Worcester, MA

Daymark Energy Advisors is a consultancy that provides economic planning and strategic advisory services to the North American electric and natural gas industries.

Consultant | 2017–Present
Senior Analyst | 2016–2017
Analyst | 2014–2016

Consulting practice includes:

- Power market modeling and price forecasting
- Power project financial pro-forma modeling and risk analysis
- Economic benefits analyses for generation and transmission infrastructure projects
- Energy policy analysis
- Integrated resource plan evaluation
- Utility ratemaking and grid modernization
- Competitive market design advisory services
- Procurement advisory services
- Potential assessment of renewable energy and energy efficiency resources
- Support for expert witness testimony

Monitoring Analytics, LLC | https://www.monitoringanalytics.com/ | Eagleville, PA

Market Analyst | 2011–2014

- Monitored PJM Interconnection and developed various metrics to assess efficiency of PJM markets specific to market design, market conduct, and market participant behavior
- Gathered transmission data and created system topology maps to analyze power flows
- Contributed to FERC filings by analyzing and reporting on PJM and member filings
- Contributed to generation of annual State of Market Reports and quarterly reports
- Utilized SQL programming to analyze PJM and produced daily reports

UgMO Technologies, Inc. | http://ugmo.com/ | King of Prussia, PA

Field Operations Manager | 2010-2011
Agronomic Data Analyst| 2009-2010

- Analyzed and summarized agronomic data for customers and research reports

TESTIMONY & PUBLICATIONS

Expert Testimony

FORUM	ON BEHALF OF	MATTER
Vermont Public Utility Commission	Stowe Electric Department	Application for request for a 7.9% rate increase to take effect on service-rendered basis August 15, 2018. Provided support for the rate increase by analyzing test year cost of service, developed an updated revenue requirement, and prepared revised rate schedules. Case No. 18-2372-TF.
Massachusetts Division of Public Utilities	Blackstone Gas Company	Petition for review and approval of Long-Range Forecast and Supply Plan for the five-year period 2018-2023. Conducted load forecast and assisted in drafting of the plan. D.P.U. 18-154. November 2018.
Rhode Island Public Utilities Commission	Rhode Island Division of Public Utilities and Carriers	National Grid's 2018 Annual Retail Rate Filing and 2018 Renewable Energy Standard Charge and Reconciliation Filing. Submitted memo addressing the accuracy of the various reconciliations in accordance with relevant tariffs. Docket Nos. 4692 and 4805. March 2018.
Rhode Island Public Utilities Commission	Rhode Island Division of Public Utilities and Carriers	National Grid's 2017 Annual Retail Rate Filing and 2017 Renewable Energy Standard Charge and Reconciliation Filing. Submitted memo addressing the accuracy of the various reconciliations in accordance with relevant tariffs. Docket Nos. 4605 and 4691. March 2017.
Massachusetts Division of Public Utilities	Blackstone Gas Company	Petition for review and approval of Long-Range Forecast and Supply Plan for the five-year period 2016-2021. Conducted load forecast and assisted in drafting of the plan. D.P.U. 16-185. November 2016.

Publications

- *Benefits and Costs of Utility Scale and Behind the Meter Solar Resource in Maryland Value,* report prepared for the Maryland Public Service Commission regarding an independent analysis of the benefits and costs of solar within each investor owned utility's service territory, November 2, 2018. Contributing Author.
- *Contract Evaluation,* confidential report prepared for a private client regarding a cost-benefits study to assess the merits of extending a contract pertaining to an interconnection in New England, April 9, 2018. Contributing Author.
- *State of Charge: Massachusetts Energy Storage Initiative,* study prepared for and in conjunction with the Massachusetts Department of Energy Resources and Massachusetts Clean Energy Center. August 25, 2015. Contributing Author.
- *The Economic Impacts of Failing to Build Energy Infrastructure in New England,* report prepared for the New England Coalition for Affordable Energy. August 25, 2015. Contributing Author.

EDUCATION

Certificate from the Institute of Public Utilities Advanced Regulatory Studies Program | Michigan State University, East Lansing, MI | 2017

Master of Environmental Economics | Pennsylvania State University, University Park, PA | 2008

B.S. Natural Resource Management | University of Delaware, Newark, DE | 2006